Center for Energy and Environment

November 2, 2012

Mr. William Grant
Deputy Commissioner, Division of Energy Resources
Minnesota Department of Commerce
95 7th Place East, Suite 500
St. Paul, MN 55101-2198

RE: The Center for Energy and Environment's Comments on Minnesota's Distributed Generation Policy

Dear Deputy Commissioner Grant:

The Center for Energy and Environment (CEE) respectfully submits the following comments on Minnesota's distributed generation (DG) policy, as follow up to the October 11, 2012 DG net metering workshop.

Sincerely,

/s/

Sheldon Strom
President

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Introduction

The Center for Energy and Environment (CEE) appreciates the opportunity to provide comments on Minnesota's distributed generation (DG) policy. It is clear that at this time, the full costs and benefits of DG are not agreed upon by relevant participants. It is also apparent that Minnesota's current policies do not adequately address the economic needs of DG customers. As the State considers changes to its DG policies, CEE believes it is important to articulate the rationale for why policy changes are justified.

Minnesota should update its policies on distributed generation for two primary reasons. The first is that without refinements in DG policies, utility customers may be prevented from pursuing self-generation options that can provide them with significant benefits. Addressing this issue requires a careful assessment of utility rates and practices that impact DG customers, including demand and standby charges. The state needs to ensure that these rates and practices are not discriminatory and reflect the actual costs to serve these DG customers.

The second reason is that over time, distributed electricity generation holds potential for new opportunities to meet Minnesota's clean energy goals and transition to a more flexible, reliable, resilient electricity grid. In order for distributed generation to meet these objectives, it will need to be evaluated in a manner that is consistent with other generation resources. Minnesota's least-cost energy planning framework provides a model for measuring how new energy investments can meet multiple policy goals, including the environmental, economic and reliability standards set forth in Minnesota statutes. The State and utilities should consider procedures such as least-cost planning that allow DG to compete equitably with other resources.

Given the current low penetration of DG in Minnesota, estimated to be 13.5 MW,[1] the state also has the flexibility to craft new policies that can uphold key energy principles, protect ratepayers, spur innovation, and maintain a robust system. The state should facilitate targeted adoption of DG in coordination with utilities and interested customers to maximize opportunities for "learning by doing." For example, by installing DG in a variety of applications and targeting distribution-constrained areas. This will create a foundational understanding of DG system operation to better inform policy decisions once higher penetration levels are approached.

Distributed Generation Principles

CEE recommends that the following principles should explicitly govern changes to distributed generation policies and practices in Minnesota:

1. **Balance the interests of customers that want DG with non-participant ratepayers, shareholders, and society through benefit-cost analysis.**

   There has been growing customer interest in rooftop PV in Minnesota, driven by a combination of lower cost panels, federal tax incentives, state interconnection policy, and utility subsidies. These customers are motivated by a variety of benefits, and while it is valuable to leverage their private investment, the State should ensure that costs are minimized for utility customers that do not install distributed generation. In order to satisfy this requirement, more quantification and analysis of actual DG costs and benefits is required. While participant costs and payback are fairly well established, system wide costs and benefits are less certain. DG represents a new business model for grid services, where bundled utility services such as reliability and grid support are disaggregated and placed behind the customer side of the meter. Estimations of the resulting costs and benefits are dependent not

[1] This includes the 11.8 MW of systems under 40kW and 1.7 MW of systems between 40kW and 500 kW. Source: Bill Grant and Lise Trudeau. "Minnesota Distributed Generation and Net Metering," webinar presented by the Minnesota Division of Energy Resources. August 15, 2012

only on the technology but on the level of penetration, the location on the grid, and the technology production profile. As noted in other states that are implementing DG policies, these system-wide valuations are challenging to assign to a single installation and generalize into a tariff.

Estimates of DG benefits can begin with more commonly quantified values. As a starting point, the energy and capacity value of customer installed generation can be compared to utility avoided costs, as put forth in CIP triennial planning documents. The following avoided cost example is from Xcel Energy's 2013-2015 plan, and shows costs for 2013:[2]

Utility Avoided Energy Costs	$30/MWh
Avoided Transmission and Distribution Capacity	$33/kW
Avoided Generation Capacity	$87/kW

Currently these costs are low, but they are likely to increase over time. Another important benefit is avoided transmission and distribution line losses, which are estimated in the range of an 8-11 percent savings. PV systems will have additional value because electricity generation overlaps with peak usage times, and because they offer protection from fuel price uncertainty. The costs and benefits that are more challenging to quantify relate to grid reliability and customer support. For example, benefits include the financial value of DG grid support (including alleviation of constraints), and the societal value of customer reliability. Costs may include increased utility distribution system costs from DG penetration, and the cost of service for self-generating customers in the form of standby or backup power. At present, there is limited Minnesota data for these valuations, and it will necessitate utilities to gather data on how existing DG is impacting utility operations.

2. **Ultimately, Minnesota's policies should facilitate a diversity of DG technologies, ownership structures, and characteristics such as dispatchability.**
   DG encompasses a range of technologies and the market continues to evolve. While rooftop PV appears to be driving the current DG market in Minnesota, it represents one option in a suite of promising distributed technologies, including combined heat and power (CHP). In the medium to long-term, higher penetration of DG will provide more value when there is mix of technologies with varied and balancing characteristics, including load following operation and demand response.[3] Policies should not ignore these options when structuring costs and benefit analysis. However, if PV is motivating current policy reform efforts, the State should explicitly prioritize that technology for a near-term cost and benefit assessment.

3. **Evaluate DG in a manner that is consistent with Minnesota's integrated energy planning framework.**
   Utility investments to facilitate DG should be considered along with the suite of options available for meeting Minnesota's energy needs, including energy efficiency and utility-scale renewable resources. This approach is used for Minnesota's integrated resource planning (IRP) process, which can be a model for this analysis (though CEE is not recommending that IRP be the vehicle for near-term policy changes). By using metrics consistent with utility IRP, DG can be evaluated as a system resource, taking into account the diversity of utilities and their portfolios. This will allow for a focus on the utility

[2] Xcel Energy Response to Division of Energy Resources Information Request No. 1, Docket No. E,G002/CIP-12-447. July 23, 2012

[3] See, for example: Hansen, Lena "Exploring the Costs and Values of Distributed Resources." Presented at the Minnesota DG Workshop, October 11, 2012.

investment costs alone, irrespective of customer willingness to pay. Since DG technologies are funded through private financing, not utility investment, it will be important to understand how this can increase the cost effectiveness of DG from the utility cost perspective.

4. **Maximize Minnesota's understanding of system costs and benefits through project documentation, performance monitoring, and evaluation of pilot projects.**

   Recognizing that current low levels of penetration allow flexibility moving forward, the state should require that near term installations, encouraged under more favorable DG structures and incentives, should provide information about performance for further evaluation. The cost of PV panels has decreased dramatically in recent years, but there is still a large variation depending on technology and site-specific installation costs. Best estimates of the current cost of PV is that it remains well above wholesale power rates. A 2012 study by the National Renewable Energy Lab quotes the national average price of residential and commercial PV at \$5.71 and \$4.59 per watt, respectively.[4] Additionally, there are federal tax credits that currently reduce net installed costs by approximately one-third to one-half. The net system cost of approximately \$4.00 to \$3.00 per watt results in a levelized customer cost of 22 to 17 cents per kWh.[5] The DOE's Sunshot program has established a target of 6 cents per kWh for utility scale installations.[6] This price could compete with wholesale prices, even if low natural gas prices continue. Given this variation and anticipated market change, utilities should carefully track the cost and performance of DG installations.

CEE Recommendations for Next Steps

Several policy options are emerging that can more effectively align customer and utility needs in the near-term. These are discussed below, and should be explored in more detail to understand the costs and benefits of different approaches to customers, utilities, shareholders, and ratepayers as a whole.

1. Until additional DG policies have been evaluated, the State should retain its net metering policy for residential and small commercial customers. However, the payments by demand- billed customers on a net metering tariff should be evaluated to ensure that the charges are appropriately reflecting the cost of serving these DG customers.

Minnesota's statutes for net metering are intended to give maximum encouragement to small customers willing to install onsite renewable and cogeneration systems.[7] Net metering provides a simple accounting method that minimizes transaction costs. For net metered PV installations, utilities obtain the benefit of excess electricity produced during on-peak times of the day. One disadvantage of net metering is that non-participant ratepayers can incur costs for the use of the system by the net metered customer. While there may be other benefits that a DG generator may provide, net metering is not a tariff that has a basis in the actual costs and benefits of a generator to the grid system. The current net metering statute sets the qualifying limit at 40 kW, though standby charges do not apply until a customer is 60 kW or larger.

[4] IRS statutes 26USC Sec25D and 26USC Sec48 provide for 30% tax credits for solar installations in residential and business properties. Business can also get accelerated depreciation under 26USC 168. This accelerated depreciation is equivalent to about a 17.5% savings in net present value terms. These credits are set to expire in 2016.

[5] CEE internal analysis: This assumes a system lifetime of 25 years, a discount rate of 5 percent, and annual production of 1,286 kWh per installed watt (source: PV Watts calculator).

[6] http://www1.eere.energy.gov/solar/sunshot/news_detail.html?news_id=16701

[7] MN Statutes 216B.164

2. Adopt DG pilot projects to test innovative policy approaches.

Utilities have the opportunity to pilot alternate tariff structures for larger DG systems that will serve to separate the value of DG to the electricity grid from the cost of providing customer power. One option is a "Buy All / Sell All" tariff structure where the utility buys the full production from a DG system, but continues to sell the customer their total usage at the applicable tariff rate. The utility "buy" rate should account for the value of different types of DG, including time of day production values for PV. There are additional benefits to consider beyond avoided energy and capacity costs, such as system reliability. Key learning opportunities from a pilot include system performance, distribution system impacts, and customer costs and usage patterns. Utilities should be allowed to collect data on customers' DG systems to gain real world experience and report on outcomes.

Other standard offer pilot programs could also be employed to test a standard pricing regime. Pilot projects could target certain market segments (e.g. mid-size solar PV) and employ pricing structures designed to appropriately reflect the value of peak coincident production, while minimizing costs paid for nonpeak generation.

3. Develop projects under a range of DG ownership models.

Xcel Energy has initiated community-owned solar gardens in Colorado and could test this model in Minnesota as well. Wright Hennepin Electric Cooperative is offering its customers the option to offset electricity bills through investment in solar PV. In addition, utilities are well positioned to design, finance, and deliver DG technologies and services to their customers, and they may be ready to test these offerings.

4. Continue to improve the knowledge base on DG in Minnesota to better inform stakeholders and regulators:

Consider the following additional activities:

- Clearly identify cost and value components of DG to assign more Minnesota-specific valuations to existing estimates.
- Develop a variety of case study scenarios under different utility tariff schedules to better understand how DG customers are impacted by these different utility tariff schedules.
- Prioritize which DG technologies will be the focus of near-term study. We recommend explicitly focusing on PV, with possible inclusion of CHP.
- Identify possible sources of revenue to support DG pilot projects.
- Evaluate DG additions and investments using IRP modeling tools.
- Demand side resources are likely to play an increasing role in Minnesota's energy supply. Identify potential alternative regulatory mechanisms that will integrate prudent investments in demand side resources with the business model of utilities.